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The reservoir rock volumetric concentration and tortuosity description of pore space of Xa field, Niger Delta Basin

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Abstract

The assessment of rock reservoir volume concentration is necessary as it accounts for the appreciable pore spaces available for hydrocarbon and other targets. Raw well d-ata from oil wells A, B and C in some parts of the Niger Delta Basin (XA Field) were used for porosity estimates in sandstone and shale formations. Using the Microsoft Excel for analysis, gamma ray log, density log with respect to depth were generated. The results of these curves were used to estimate porosity and create models for porosity-formation factor with respect to density effect. The major findings revealed the average porosity values as about 20% for well A, 17% for well B and 19% for well C. The results show that increase in density gives rise to a decrease in porosity in both lithologies. In order to establish a relationship between porosity of this Field rock reservoir, a plot of porosity with formation factor due to density influence was necessary. These curves lead to several equations with the average for linear curves as $F_D = -400\emptyset_{X_A} + 98.08$ and $F_D = (-0.2\emptyset_{X_A} + 4.9) \times 10^{-3}$ for fractional and percentage porosities respectively. These models show that both parameters are strongly related with coefficients of 0.9723 (for both plots from well A), 0.8274 (for both plots from well B) and 0.9689 (for both plots from well C) for XA Field. These results correspond to the non-linear relation, $\emptyset_{X_A} = 0.8006F_D^{-0.465}$ as the original values of the cementation exponent and the tortuosity factor are obtained, if the formation factor is considered as the subject.

Keywords: Density; Formation Factor; Porosity; Reservoir; Sand; Shale

1 Introduction

The porosity of a sedimentary deposit is a significant factor for estimating the possible bulk of hydrocarbons available [1]. Porosity of a formation is essential in assessment of fluid content, potentiality of fluids flow and recaptures volumes in a pool. Porosity is one of the vital qualities of any hydrocarbon basin or reservoir. Reservoirs have porosity ranging from 5% to 45%, though most of them are within 10% and 20% [2]. Porosity field is also vital as it may be used to calculate abnormal pressure areas as oil-well is drilled [3,4]. The movement of subsurface fluids depends on porosity and permeability [5].

Chukwueke *et al*. [6] worked on surface porosity evaluations making use of geophysical logs and realised porosity information for sandstone as 43.38% and 70.09% for shale. Okiongbo [7] considered north-eastern part of the Niger Delta and noted porosity data to be in the range of 10% and 25%. Ikeagwuani [8] finding indicated the porosity as 15% corresponding to the depth of 4267.2metre (m) and 35% conforming to 5000ft. More so, Akankpo *et al*. [1] worked on porosity modelling for lithologies of the formation identified as sand and shale, and concluded that Porosity values range from 0.013% to 94.08%; they also stated based on their result, that porosity decreases with depth.

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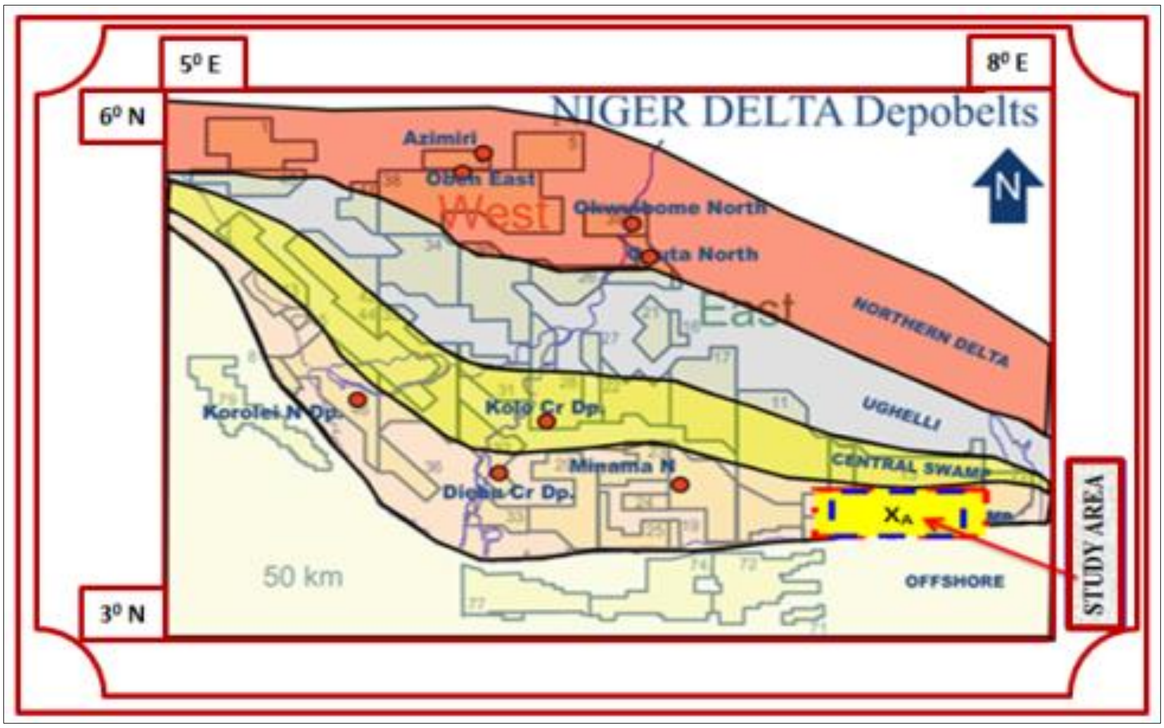
The goal is to estimate porosity in sandstones and shales in parts of the Niger Delta using raw well data and obtain a suitable linear model relating formation factor to porosity in the $\mathbf{X_A}$ Field. In order to achieve this, gamma ray log and density curves with respect to depth have to be generated, identify the possible API index of lithologies from gamma ray log, identify the sandstone and shale lithologies, and model the formation factor-porosity relationship. This study assesses the possible pore spaces for the promising amount of hydrocarbons that may be available or the potentiality of fluids movement as one of the important features of any hydrocarbon reservoir is porosity. It further makes available, the data describing a parameter that is linearly relate to water saturation.

1.1 Location and Geology

$\mathbf{X_A}$ Field is found in the Eastern Niger Delta, South of Port Harcourt, Rivers State, Nigeria. It is disconnected from the large Cawthorne Channel Field by a major antithetic (counter regional) normal fault [9]. The Niger Delta is located between latitudes 3^0N and 6^0N; longitudes 5^0E and 8^0E [10-13]. About 80% of the Niger Delta area is made up of Akata, Agbada and the Benin formations [14]. The area of study is $\mathbf{X_A}$ (Figure 1). The depobelts are highlighted in Figure 1 and the sediment volume is about 5.0 x 10^5km^3 [15]. The oil in this basin is in the class of Akata-Agbada [16-18]. More of marine shales made up the Akata formation with an expected width of up to 7.0 x 10^3m [19]. The Agbada formation is the major oil reservoir in the Niger Delta. The grains of rocks are identified due to their shapes, sizes, mineral structures, the age and time of deposition [20-22]. Niger Delta experiences wet and dry periods in a year [23]; average rain in a month during wet season is about 1.35 x 10^2mm and this falls to 6.50 x 10^1mm during dry season [24-28].



Source: Kulke [29]

Figure 1 Niger Delta Depobelts and Location of the Study

2 Theoretical Concept

2.1 Porosity

Porosity of a formation is important in the evaluation of fluid content, potentiality of fluids flow and recaptures amounts in a pool [30]. The volumetric concentration of pore space can be determined using equation (1).

$$\emptyset_{X_A} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad \ldots\ldots\ldots\ldots\ldots(1)$$

where $\emptyset_{X_A}$ is the porosity; ρ_{ma} is grain matrix density; ρ_f is fluid density; ρ_b is bulk density of the formation [31]. According to NExT PERF [32], the the fluid density is considered within 1.0 and 1.1. If gas is present, the actual fluid density will be < 1.0 and the calculated porosity will be too high [32].

Porosity estimation may also be carried out using the relationship given by Archie [33]. This is expressed as:

$$F = \frac{a}{{\emptyset_{X_A}}^m} \quad \ldots\ldots\ldots\ldots\ldots\ldots(2)$$

(https://wiki.aapg.org/Standard_interpretation [34])

$\emptyset_{X_A}$ is the porosity; a is rock constant and varies as $0.62 < a < 1.00$; m is the cementation factor. It depends on the grain size and complexity of the paths between the pores (tortuosity). It varies as $2.0 < m < 3.0$. F is a function of rock texture [35]. According to https://wiki.aapg.org/Standard_interpretation [34], in soft formation, a may be taken as 0.62 and m as 2.15; F is the formation factor describing the tortuosity of the conductivity paths (pore space) in the rock.

Porosities are effective porosity and total. Total porosity involves porosity that can never be accessed as a result of the pores not being connected. Effective porosity means the pores are connected with flow channels. The pore produced during the original sedimentation and lithification of the reservoir is called primary porosity. The pore generated later during varied geologic process following deposition, such as fracture or dissolution, are called secondary porosity. Secondary porosity comes from mechanical and geochemical developments.

Well logs can help compute porosity using either the gamma-ray log or the neutron density logs. The gamma-ray logs use an algorithm to formulate the bulk density. Assessment of porosity is possible with Equation (1) and Equation (2). Sandstones porosity is about 10 to 40%. It may approach 80 percent in deposited unconsolidated sediments.

2.2 Density Log and Gamma Ray (GR) Log

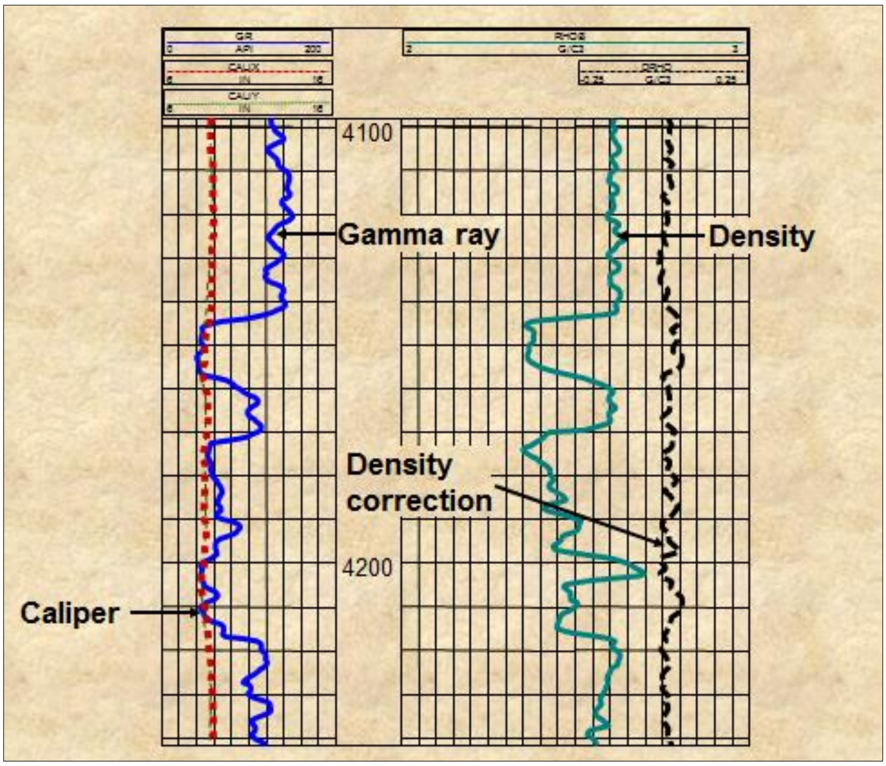
Geoscientists have acknowledged that porosity calculation from bulk density logs is more accurate [36]. A zone with higher density defines the number of electrons with greater densities. It reduces the GR strongly; thus, a lower count rate of GR is noted at the sensors; similarly for a zone with low density. A low-density formation decreases the GR less than a zone with high density; therefore, a higher GR count rate is noted [37]. Figure 2 presents a typical density log. Equation 3 defines the connection.

$$n_e = \frac{N_{an}Z}{A}\rho \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3)$$

[36,38]

where n_e is the electron density number in electron cm^{-3}; N_{an} is the number Avogadro number; Z is the atomic number and A is the atomic mass.

Gamma ray log is used to characterise lithology. The gamma ray energy emitted from the lithologic units are signatures to the lithology. A scintillation detector in the tool used to detect gamma rays and the numbers detected are recorded in American Petroleum Institute (API). Radioactive elements are seen in illite, in organic matter as well as thorium in heavy minerals like zircon, sphene and others. Minerals such as Zircon, Sphene, Monzanite and Allanite are more abundant in shales than sandstones; therefore, shales have higher gamma ray API responses compared to sand.



Source: NExT PERF [32].

Figure 2 Density log and some other logs

3 Materials and Method

3.1 Materials

Microsoft Excel was used for data loading, processing, plots/curves, diagrams and other computations. Data acquired from the onshore Niger Delta oilfield are

- Well History
- Well Location
- Raw well data, and
- Geology

3.2 Method

The data used are ones from the deeper surface processes information. Three wells were available for this study (well A, well B and well C). This information helps to generate suites of log such as depth, gamma ray and density. These data were analysed using Microsoft Excel. The different stages of workflow (Figure 3) employed include: Data loading, conditioning, editing and processing, the sandstones lithology and shale lithology identification and plotting density curves. The dominant lithology at the top of Akaso reservoir is seen as shale with API value greater than 75; the dominant lithology in the reservoir is sandstones with API value less than 75. The depths with shale-sand-shale lithology were marked and considered for porosity estimates.

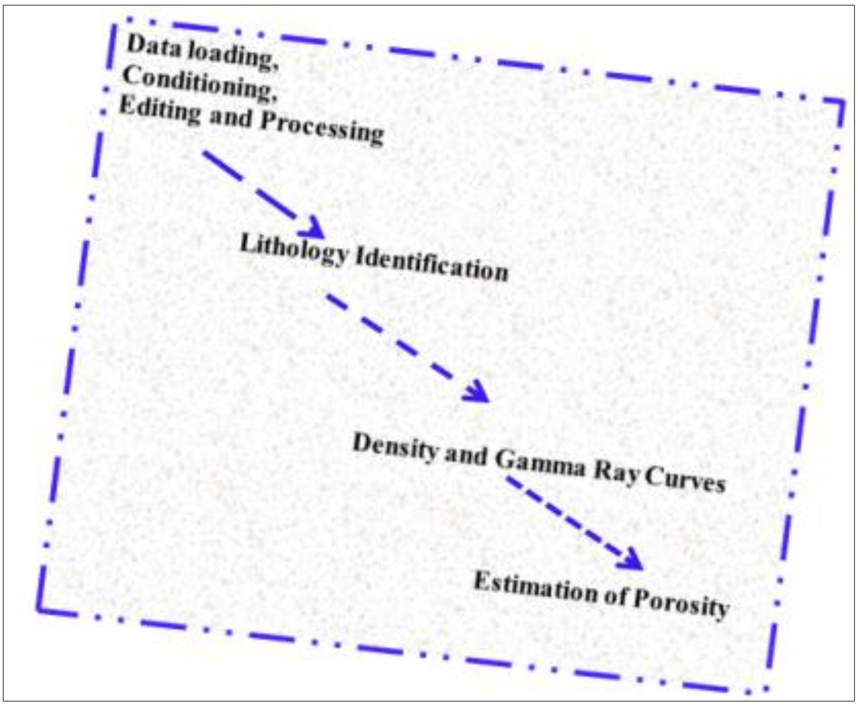


Figure 3 Workflow of the study

4 Results

Three wells of **X$_A$** Field were analyzed in this study and the results are presented in Figures 4 to 8. The results of discrimination are in Figures 4, 6 and 8. Porosity estimates result as a function of density and depth. Figures 5, 7 and 8 present these results for wells A, B and C respectively.

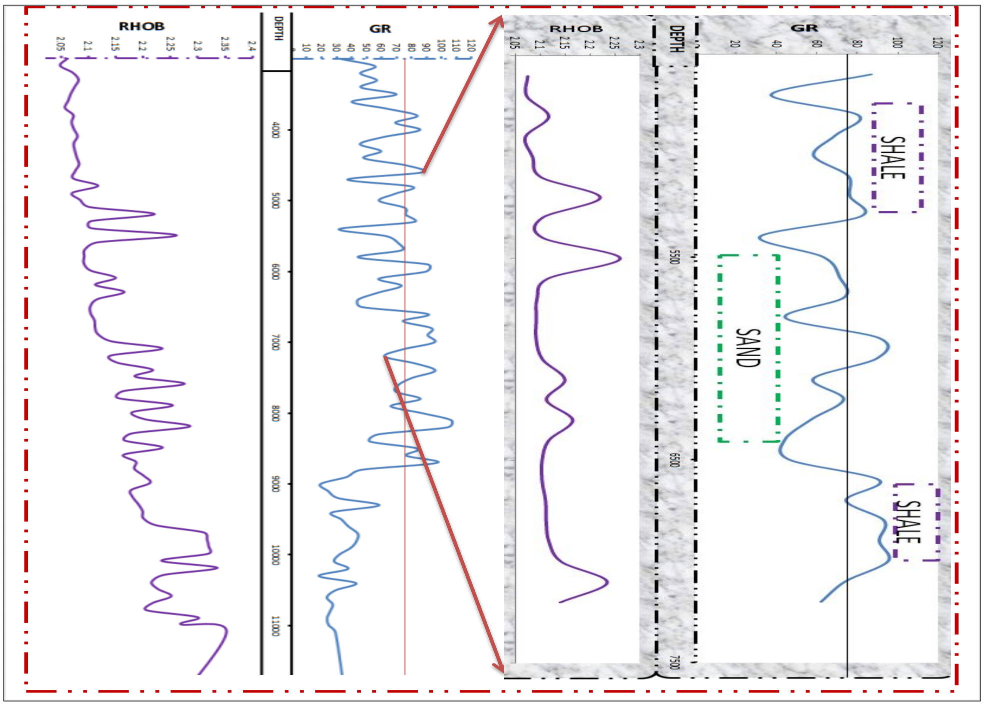


Figure 4 Density (in purple) and Gamma Ray (in blue) Curves with respect to Depth indicating the Sandstones and Shales Lithologies of Well A

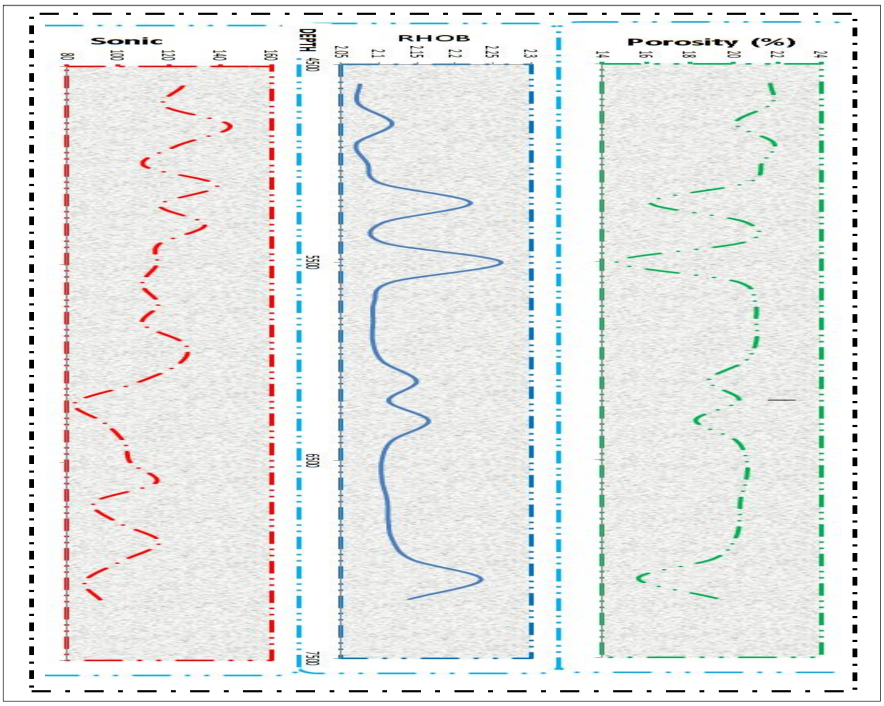


Figure 5 Porosity (in green) Estimates from Well A

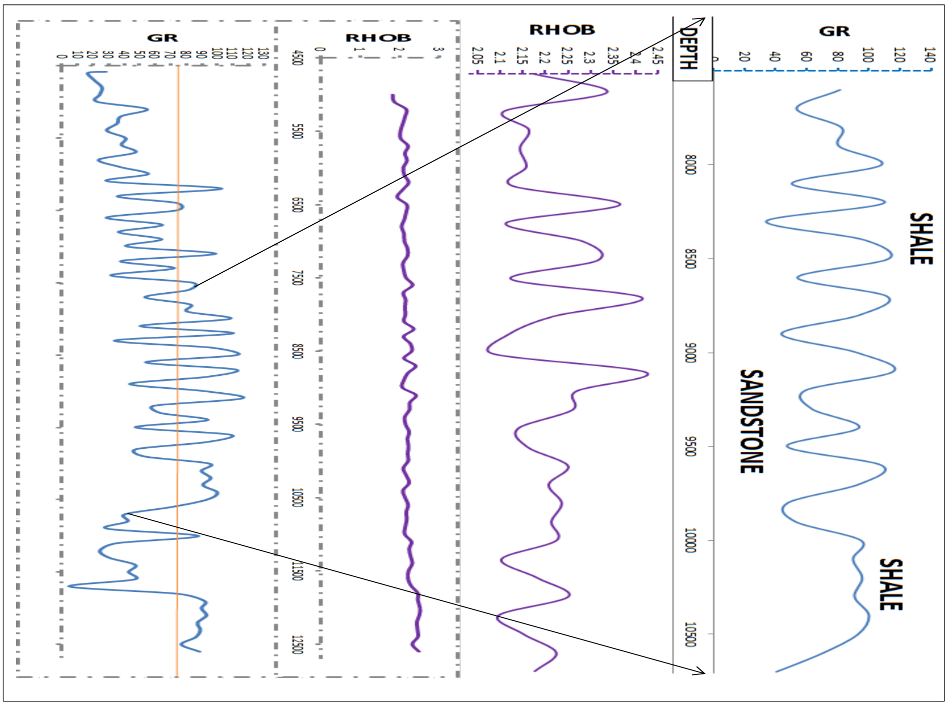


Figure 6 Density (in purple) and Gamma Ray (in blue) Curves with respect to Depth indicating the Sandstones and Shales Lithologies of Well B

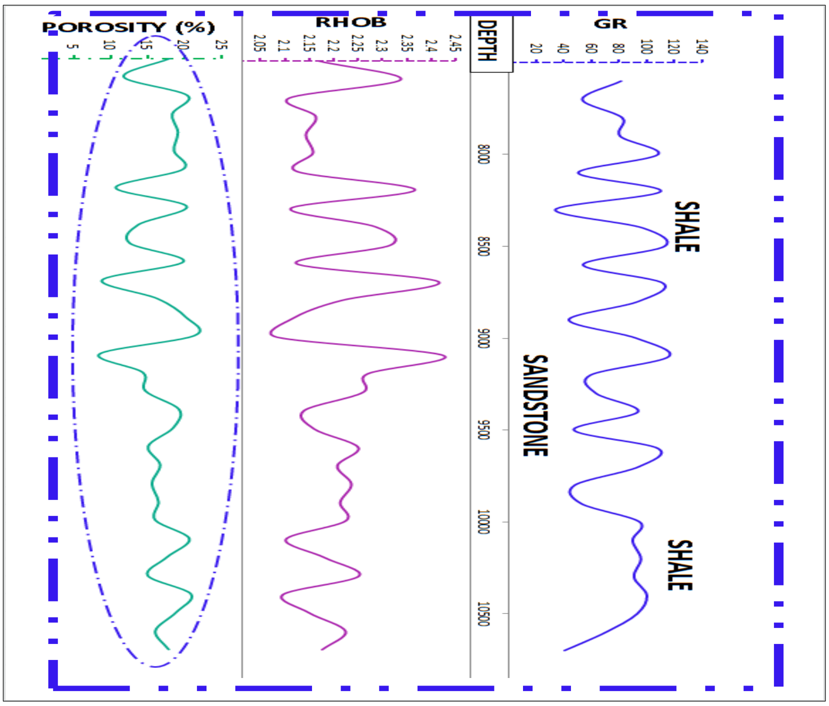


Figure 7 Porosity (in green) Estimates from Well B

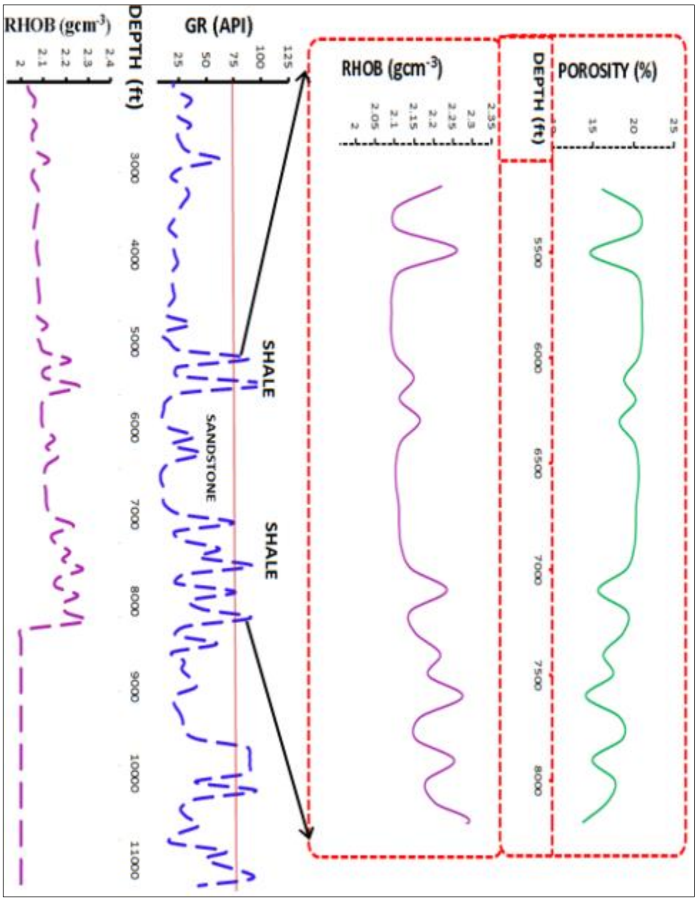


Figure 8 The result of Porosity (in green) Estimates from Density (in purple) and Gamma Ray (in blue) Curves with respect to Depth from Sandstones and Shales Lithologies of Well C

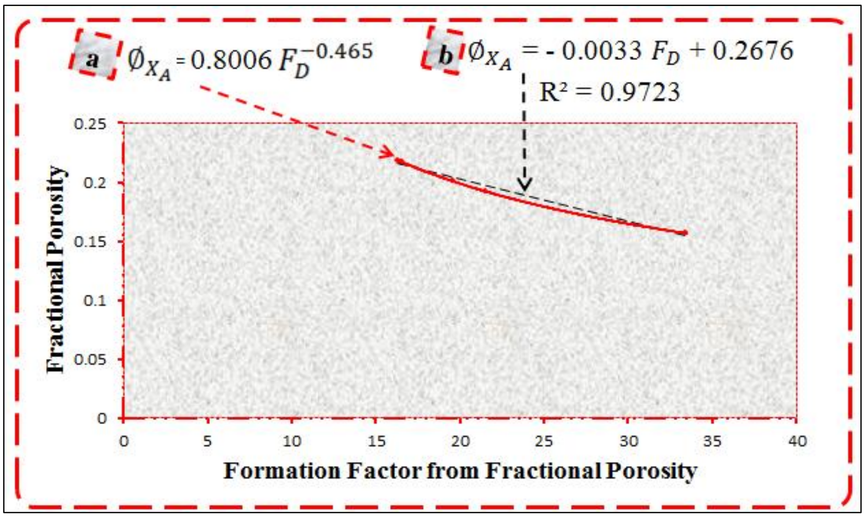


Figure 9 Fractional Porosity-Formation Factor curves (a) non-linear (b) linear for well A

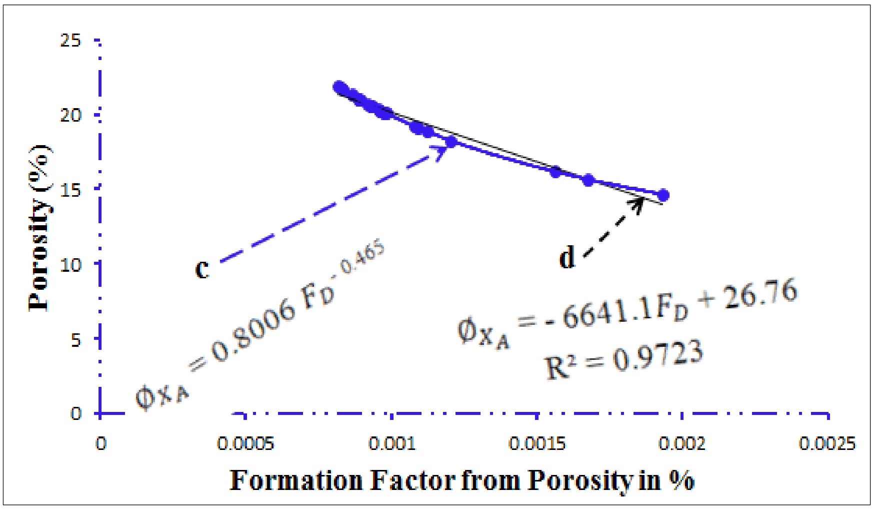


Figure 10 Percentage Porosity-Formation Factor curves (c) non-linear (d) linear for well A

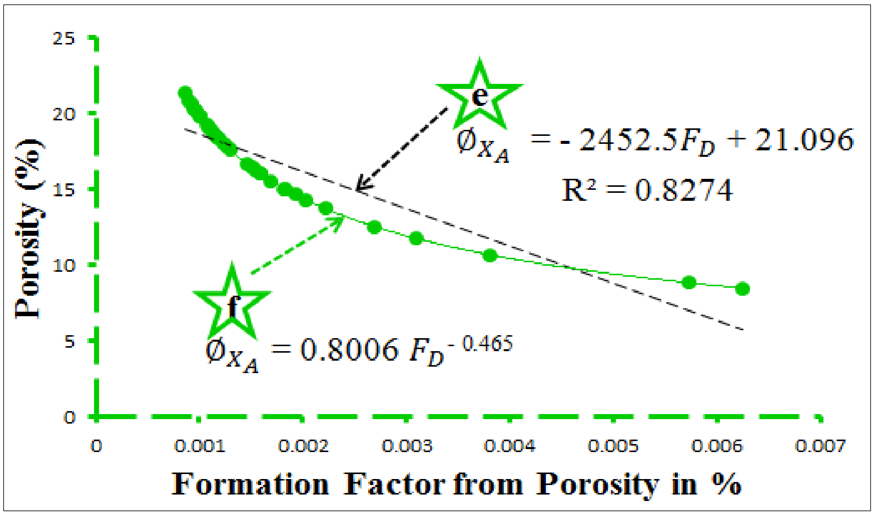


Figure 11 Percentage Porosity-Formation Factor curves (e) non-linear (f) linear for well B

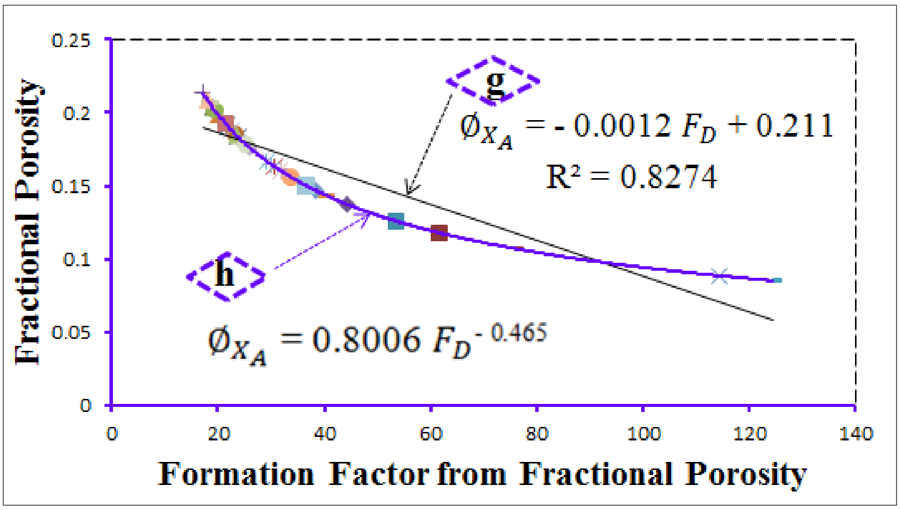


Figure 12 Fractional Porosity-Formation Factor curves (g) non-linear (h) linear for well B

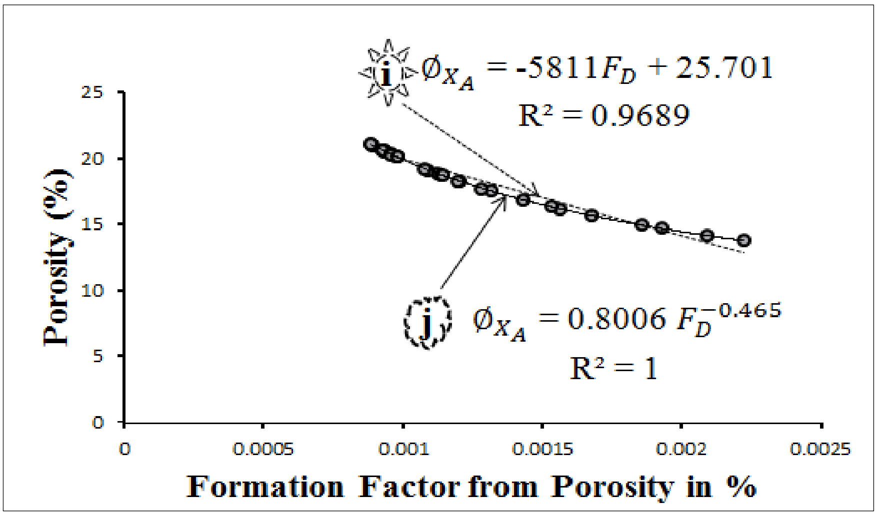


Figure 13 Percentage Porosity-Formation Factor curves (i) non-linear (j) linear for well C

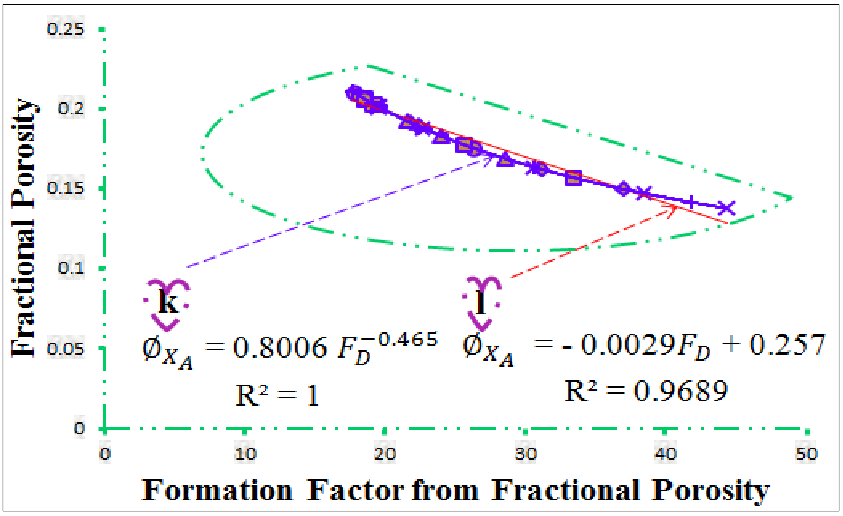


Figure 14 Fractional Porosity-Formation Factor curves (k) non-linear (l) linear for well C

5 Discussion

An investigation on porosity estimates in sandstones lithology and shales lithology as a function of density and depth had been carried out. The Field location considered is **X_A**, Eastern part of Niger Delta. Using Microsoft Excel, the results as presented in Figures 4 to 7 were obtained.

The raw data was analyzed and presented in the form of suites of logs (Figures 4, 6 and 8) which include density log (purple) and gamma ray log (blue) with respect to depth. Gamma ray log was used to identify the lithologies (sandstone and shale) since our focus is on these two formations (Figures 4, 6 and 8). The dominant lithology at the top of **X_A** reservoir is seen as shale with API value greater than 75; the dominant lithology in the reservoir is sandstones with API value less than 75. The corresponding depth and density log generated were adequate for the porosity estimates (green) as seen in Figures 5, 7 and 8.

Equation (1) was employed in Microsoft Excel for mathematical analysis. The outcomes showed that the porosity ranges from 15.8% to 22.0%, 8.0% to 22.5% and 14.0% to 21.5% for wells A, B and C respectively; resulting in the average values of about 20% for well A, 17% for well B and 19% for well C (this means that the average porosity obtained ranges within 17% to 20% in the **X_A** Field). The result also indicated that an increase in density gives rise to a decrease in porosity irrespective of the lithology; density increases with depth.

In order to relate porosity estimates with formation factor as this defines the tortuosity of the pore space, the plots of porosity against formation factor were necessary for well A (Figures 9 and 10). These curves were also obtained for wells B and C (Figures 11 to 14). Equations (4) to (9) were generated from the linear curves from fractional porosity (Equations 4 to 6) and percentage porosity (Equations 7 to 9) both with density effect.

$$\emptyset_{X_A} = -0.0033\,F_D + 0.2676 \quad \text{..........(4)}$$

$$\emptyset_{X_A} = -0.0012\,F_D + 0.2110 \quad \text{..........(5)}$$

$$\emptyset_{X_A} = -0.0029\,F_D + 0.2570 \quad \text{..........(6)}$$

$$\emptyset_{X_A} = -6641.1\,F_D + 26.760 \quad \text{..........(7)}$$

$$\emptyset_{X_A} = -2452.5\,F_D + 21.096 \quad \text{..........(8)}$$

$$\emptyset_{X_A} = -5811.0\,F_D + 25.701 \quad \text{..........(9)}$$

Equations (4) and (7) were obtained from the analysis of data from well A. Equations 5 and 8 were achieved by analysing well data B. Moreso, Equations (6) and (9) resulted from the analysis of processed data of well C.

Averaging the above equations correspondingly and consider the formation factor as the subject, give rise to Equations (10) and (11) for fractional and percentage porosities respectively.

$$F_D = -400\emptyset_{X_A} + 98.08 \quad \text{..........(10)}$$

$$F_D = (-0.2\emptyset_{X_A} + 4.9) \times 10^{-3} \quad \text{..........(11)}$$

These models show that both parameters are strongly related with coefficients of 0.9723 (for both plots from well A), 0.8274 (for both plots from well B) and 0.9689 (for both plots from well C) for **X_A** Field. These results correspond to the non-linear relation, $\emptyset_{X_A} = 0.8006F_D^{-0.465}$ as the original values of the cementation exponent and the tortuosity factor are obtained, if the formation factor is considered as the subject.

6 Conclusion

Porosity estimates is significant for estimating the potential volume of hydrocarbons it may contain as it considers the pore spaces in a formation. Our findings show that the porosity ranges from 15.8% to 22.0%, 8.0% to 22.5% and 14.0% to 21.5% for wells A, B and C respectively. This results in the average values of about 20% for well A, 17% for well B and 19% for well C (this means that the average porosity obtained ranges within 17% to 20% in the **X_A** Field). The results show that increase in density gives rise to a decrease in porosity irrespective of the lithology. Density also increases with depth. This porosity results improves much better in the sandstone lithology than shale lithology. The porosity-formation factor model was also achieved.

Compliance with ethical standards

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No potential conflict of interest.

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